Comments of NRG on Massachusetts "Ratemaking Straw Proposal" from "Electric Rates Task Force"

I. Introduction

NRG appreciates the effort and diligence from the MA Department of Energy Resources ("DOER") team throughout the "Electric Rates Task Force" ("ERTF"), culminating with the release of the "Ratemaking Straw Proposal." We recognize the high volume of work that went into convening the expert presentations and stakeholder discussions.

The NRG Retail Companies provide competitive electric generation supply as well as other energy-related products and services to residential and non-residential customers in the Massachusetts competitive retail market. The NRG Retail Companies also currently provide electric generation supply to more than 30 cities and towns in Massachusetts through municipal aggregation programs. Across North America, NRG serves 8 million energy and energy services customers, including through its smart-home company, Vivint, which has a technology-development office in Boston.

Our vision is for every customer in the Commonwealth to have near full control over their electric bill. Indeed, as DOER has stated, implementing Time-Varying Rates ("TVR") is a critical opportunity to promote affordability in Massachusetts. With this control, NRG can provide our customers with the products, services, and insights to reduce their energy bills.

Today, customers in the Commonwealth have minimal control over their bills. The deployment of AMI is a foundational step toward empowering customers with that control. However, it is insufficient without data access/data settlement policies and rate design that sends the right price signals to customers. The "Ratemaking Straw Proposal" is a critical step toward sending the right price signals to customers and aligning cost allocation with cost causation. We urge the DOER to file the proposal with the Department of Public Utilities ("DPU") and to incorporate the recommendations we provide below.

Critically, the "Ratemaking Straw Proposal" will fail to realize its promise without proper data access and data settlement. As such, we strongly support the DOER's statement on Slide 47 that the "DPU investigation should also resolve outstanding issues regarding reporting interval data to ISO-NE for load settlement and capacity tag calculations." DOER recommends this DPU investigation take place in the first half of 2026. Indeed, Electric Distribution Companies ("EDCs") must report interval data to ISO-NE for load settlement and capacity tag calculations for TVR to be possible. NRG appreciates and supports the DPU's statements on this topic in their Order from December 15, 2025, opening an investigation in DPU 25-200, but notes there is no timeline for DPU action.[1] **When DOER files their petition with the DPU in early 2026, DOER should urge the DPU to "resolve outstanding issues regarding reporting interval data to ISO-NE for load settlement and capacity tag calculation" by the end of the first half of 2026.** Given statements from the EDCs regarding the longer timeframe they expect it to take for them to develop this capability, a decision by the DPU on these important issues by June 2026 is necessary to enable TVR consistent with DOER's desired timeframe.

We've structured the rest of our comments as follows in two sections:

1. For recommendations in the "Ratemaking Straw Proposal" that we strongly support, we note those under the heading "**NRG Strongly Supports these Ratemaking Recommendations from the "Ratemaking Straw Proposal."** NRG filed four sets of comments with the Interagency Rates Working Group ("IRWG"), and those comments detail our reasoning for strongly supporting these recommendations. For brevity, we avoid restating them here.

2. For recommendations in the "Ratemaking Straw Proposal" that require modifications, we propose modifications and our rationale in the section "Recommendations that Require Modification."

II. NRG Strongly Supports these Ratemaking Recommendations from the "Ratemaking Straw Proposal"

- **DOER Recommendation:** Design a single, consolidated TOU peak period across supply, distribution, and transmission (Slide 13)
- **DOER Recommendation**: Differentiate TOU rates by season (Slide 16)
- **DOER Recommendation**: TOU rate design should adapt to system conditions (Slide 19)
- **DOER Recommendation**: Automatically enroll all residential customers on TOU rate (Slide 22)
- **DOER Recommendation**: Allow low-income customers to opt-out and offer additional bill protections for low-income customers, such as shadow billing (Slides 23 and 24)

III. Recommendations that Require Modification

NRG strongly supports DOER's recommendation to "Allocate bill components to TOU periods based on cost causation/allocation" (Slide 15). However, we recommend several modifications

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[1] In the recently issued Order opening an investigation in D.P.U. 25-200, DPU stated its intention to "open a new proceeding to investigate reporting of AMI interval data to ISO New England for load settlement and capacity tag calculations, accelerated switching, and dynamic rate-ready TVR offered by competitive suppliers and municipal aggregators." Order at 24. NRG applauds the DPU's acknowledgment that "resolving these issues is key to allowing competitive suppliers and muni aggregators to offer TVR and "improving customers' understanding and control over their electric bills." Order at 24

on transmission costs to enable ratepayers in Massachusetts to avoid the ISO-NE need captured on Slide 9 for "$7-9 billion in new transmission costs by 2050 if load growth is not managed."

DOER recommends that transmission costs should be "allocated to peak hours in all months." NRG agrees that this will enable customers who reduce their energy usage during these peak hours to reduce the transmission cost portion of their bill as well as the transmission costs that ISO-NE allocates to the relevant "Transmission Owner" for the customer. DOER should proceed with this recommendation, in part.

But this recommendation is insufficient for reducing the transmission costs for all customers in the Commonwealth, and the $7-$9 Billion in potential new transmission.

To avoid that need, we recommend that DOER's petition propose:

1. **Time-Varying Rates that accurately reflect the hours of the year that cause the need for new transmission**. This is consistent with DOER's statement on Slide 11 that "Cost studies that identify drivers of incremental system costs ensure that customer classes are properly assigned costs to serve that class." Under the "Ratemaking Straw Proposal," it appears that transmission costs would be spread evenly across the peak hours of all 12 months of the year. Customer usage in July will likely have a much greater impact on the need for new transmission than in April, and TVR should reflect that reality.

   To effectuate this recommendation, DOER should collaborate with DPU, the New England Conference of Public Utilities Commissioners ("NECPUC") and the New England States Committee on Electricity ("NESCOE") to urge ISO-NE to share the hours of the year that are driving the need for the new transmission investment cited in their "2050 Transmission Study," and the amount of load reduction needed to defer and avoid the investments. Furthermore, DOER should collaborate with the same entities to urge transmission owners to share the hours of the year that drive the need for "local reliability" projects, and the amount of load reduction needed to defer and avoid the investments. **We recommend that DOER's petition containing the "Ratemaking Straw Proposal" encourage DPU to convene stakeholders, including ISO-NE and transmission owners, to provide this information during the investigation phase in the first half of 2026**.

   Once those hours are identified, those potential marginal costs should be factored into TVR. In the long-term, all ratepayers will benefit from avoiding the $7-$9 Billion in transmission costs.

   As evidenced by transmission costs over the last 10 years, ratepayers will suffer from a muted price signal for avoiding new transmission. In August 2025, ISO-NE Regional Network Service costs (transmission) were $16,167/MW-mo or 37% of total wholesale costs.[2] In August 2015, it was about half that, at $8,700/MW-mo and 27% of total wholesale costs.[3] For all the focus on capacity costs, transmission cost are now several times higher than capacity costs.

2. For customers served by municipal aggregators and/or retail suppliers, ISO-NE should allocate transmission costs directly to those municipal aggregators and/or retail suppliers that wish to have that option, and not the relevant transmission owners for those customers. This is similar to how ISO-NE allocates capacity costs today and how PJM allocates both capacity and transmission costs. If municipal aggregators and retail suppliers were allocated these costs, they would be motivated to provide their customers with the products, tools, and insights that would allow customers to reduce usage during these peak hours. As a result, these customers would reduce the transmission portion of their bills, and reduce the amount of transmission that needs to be built in ISO-NE.

Under the status quo, transmission owners simply pass through these costs to customers, and in some cases, benefit from building additional transmission. Municipal aggregators and retail suppliers have additional motivation for enabling customers to manage these costs. While we recognize that neither DPU nor DOER have jurisdiction over such a change, we believe it is worth collaborating with NECPUC, NESCOE, and other stakeholders to explore what ISO-NE changes would be necessary to effectuate this recommendation.

Finally, DOER recommends a 5-hour window for the on-peak component of TOU rates. NRG recommends a shorter window, with 4-hours at most. It is unrealistic to expect customers to reduce their grid consumption for so long (e.g., turning the AC down or off during a heat wave) and enabling technologies such as storage typically lack 5-hour duration. Moreover, as slide 18 demonstrates, four hours will avoid the majority of costs that five hours would avoid. In the end, having more customers engaged will lead to higher total avoided costs.

If certain distribution networks peak outside of those four hours, a more targeted solution is likely appropriate.

Conclusion

NRG strongly supports many of DOER's "Rate Design Recommendations." However, when DOER petitions the DPU, we recommend that DOER:

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[2] https://www.iso-ne.com/static-assets/documents/100028/2025_08_nlcr_final.pdf

[3] https://www.iso-ne.com/static-assets/documents/2015/11/2015_09_nlcr_final.pdf

1. Urge the DPU to "resolve outstanding issues regarding reporting interval data to ISO-NE for load settlement and capacity tag calculation" by the end of the first half of 2026
2. Propose Time-Varying Rates that accurately reflect the hours of the year that cause the need for new transmission
3. Encourage DPU to convene stakeholders, including ISO-NE and transmission owners, to provide information during the investigation phase in the first half of 2026 regarding the hours that drive the need for new transmission

Thank you for your consideration of these comments and please contact us with any questions.

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